UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Remedying Undue Discrimination	)	
Through Open Access Transmission Service	)	Docket No. RM01-12-000
And Standard Electricity Market Design	)	

AFFIDAVIT
OF
WHITFIELD A. RUSSELL

1. My name is Whitfield A. Russell. I am a public utility consultant and principal in Whitfield Russell Associates. I hold a Bachelor of Science degree in Electrical Engineering from the University of Maine at Orono, a Master of Science degree in Electrical Engineering from the University of Maryland, and a Juris Doctor degree from Georgetown University Law Center. I have been accepted as an expert on bulk power systems in more than 150 proceedings before State and Federal courts, administrative agencies and other tribunals in more than 30 States and in two Canadian provinces. My complete resume and a description of cases on which I have worked are attached as Attachment No. 1 (WAR-1) to this Affidavit.

2. I have prepared this Affidavit on behalf of the Ormet Primary Aluminum Corporation ("Ormet"), a subsidiary of the Ormet Corporation. The purpose of this affidavit is to express Ormet's comments on (a) paragraphs 267 and 268 of the Commission's NOPR on Standard Market Design ("SMD") related to transmission losses (including the appropriate measurement of losses), and (b) paragraphs 367, 368 and 369 related to the Seven Factor test set forth in Order No. 888 (including the appropriate treatment of facilities within the transmission function).

TRANSMISSION LOSSES

3. The SMD NOPR addresses transmission losses beginning at paragraph 267 as follows:

> b. Transmission Losses
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> 267. When energy is transmitted from a point of receipt to a point of delivery, some of the energy is lost due to resistance on the wires. These transmission losses are a cost of transmission and commonly are recovered on an average cost basis from all transmission customers. As noted earlier, we are proposing that energy prices and the associated transmission usage charges be based on marginal costs, in order to promote economic efficiency. We seek comment on whether transmission losses should be recovered on the basis of the marginal cost of losses or if they should be recovered on the average cost of losses. There are advantages and disadvantages to each approach. Using marginal losses would promote a more efficient use of the transmission system. However, as discussed below, charging marginal losses will collect surplus revenues that must then be returned to transmission customers. On the other hand, the advantage of charging average losses is simplicity. If average losses are charged, the losses collected from customers would equal actual losses. There would be no need to create a mechanism to return surplus losses.
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> 268. For customers purchasing transmission service to complete bilateral transactions, we see value in allowing transmission customers to pay for their assigned losses either in cash or in kind. To pay in cash, the customer would pay the market price for its assigned MWhs of losses, which would be included in the applicable transmission usage charge. Thus, the MWh of energy injected at the point of receipt would equal the MWh withdrawn at the point of delivery. The transmission provider would procure the energy used for losses from its energy market. To pay in kind, the customer would supply energy at the point of receipt in the amount of its assigned losses. Thus, the MWhs injected at the point of receipt would exceed the MWhs at the point of delivery by the amount of the assigned losses, and the customer would pay in cash only the congestion component of the transmission usage charge.[1] We note, however, that some

[1] The amount of energy needed for losses would not be known until the close of the market. For transactions in the day-ahead market, the Transmission Provider would inform each customer that wishes to supply losses in kind (after the close of the day ahead market) of the amount of its assigned losses (in MWh), and that amount would be included in the customer's day-ahead schedule. For transactions in the real-time market, the Transmission Provider could provide an estimate in advance of the amount of each

> commenters in our outreach process expressed concern that allowing customers to provide losses in kind may unduly complicate the scheduling process, especially for transactions that involve multiple Independent Transmission Providers. We seek comment on whether transmission customers should have the choice of paying for losses in cash or in kind, or alternatively, whether all transmission customers should be required to pay for losses in cash.

4. As a summary response on transmission loss issues, Ormet recommends that:

   a. Transmission losses should be recovered on the basis of average losses (with periodic true-ups to match loss recoveries to actual losses) in lieu of being recovered on the basis of marginal losses.

   b. The Commission should clarify that the pancaking of transmission losses is to be eliminated, both on transactions between zones within each RTO and on transactions that cross the boundaries of RTOs.

   c. Losses (and access charges) should be discounted for those transmission customers taking service at higher voltages.

   d. Transmission customers retain the option to provide transmission losses in kind.

COSTS OF TRANSMISSION LOSSES

5. Transmission losses are a potentially immense economic issue to transmission customers of RTOs. As the Federal Energy Regulatory Commission Working Paper on Standardized Transmission Service and Wholesale Electric Market Design (March 15, 2002) stated:

> Even within a region, a poorly designed or inefficiently managed transmission system can result in significant increased costs to customers. It is useful to review the approximate costs of electric generation and transmission to see the impact that transmission can have on energy costs.

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customer's assigned losses. However, since actual marginal losses would not be known until after the fact, the customer would be charged or credited at the applicable LMP for any under- or over-provision of losses.

Consider these approximate costs as viewed by retail customers (excluding distribution and load-serving entities' (LSEs) operating costs, which represent about 15% or less of the average retail bill) for two regional markets, for the year 2000:

	PJM		NY	
	$ Millions	% of Total Cost	$ Millions	% of Total Cost
Energy Costs	$9,822	92.2%	$7,599	88.6%
Congestion Costs	$134	1.2%	$1,209	14.1%
Line Losses	$491	4.5%	$380	4.5%
Transmission Revenue Requirement	$832	7.8%	$979	11.4%
Total Cost	$10,654	100%	$8,578	100%
Peak Load (MW)	49,417		30,200	

These markets are used because we have information readily available for them. These figures illustrate several important points. First, within the delivered retail bill, the cost of transmission alone is small compared to the cost of generation, but these costs are still large in absolute terms. Second, two elements which are substantially affected by the design and operation of the transmission system have a significant effect on energy costs, i.e., the cost of transmission congestion (which is actually the opportunity cost of having too little transmission) and the cost of line losses (the additional generation that must be produced to make up for energy lost in the delivery of electrons through the grid, averaging about 5% of total electricity produced). Third, the costs hint at the substitutability between generation and transmission – specifically, as the grid becomes constrained, energy costs rise markedly due to the redispatch of more expensive plants to work around the transmission constraints.[2]

[2] Note that the Energy Costs and Transmission Revenue Requirements are summed to reach Total Cost. Congestion Costs and Line Losses are implicitly included as subcategories of Energy Costs. The Commission Staff explained the sources for the PJM/NY Table as follows:

> Energy Costs for each independent system operator (ISO) are derived from Form 1 data for each of the utilities in the ISO. It is calculated as the sum of Total Power Production Costs (Form 1, page 321, line 80) of each of the utilities in the ISO. Congestion costs are from the websites of each ISO. Line losses are assumed to be 5% of Energy Costs (4.5% of Total Cost). The transmission revenue requirement for each ISO is the sum of the annual transmission revenue requirements of each utility in Attachment H to the OATT of each ISO. Total Cost is the sum of Energy Costs and the Transmission Revenue Requirement. Peak load for PJM Interconnection, L.L.C. (PJM) is from "PJM Interconnection State of the Market Report 2000." Peak load for New York Independent System Operator (NYISO) is from "Power Alert: New York's Energy's Crossroads" (March 2001).

6. These portions of the Commission's Working Paper on Standardized Transmission Service document the immensity of the costs borne by society in the form of transmission losses and transmission congestion.[3] Inaccuracies and inequities in loss methodologies continue to provide a substantial economic windfall to transmission owners and their generating affiliates. Some methodologies for quantifying and allocating transmission losses continue to allow transmission owners to collect losses far in excess of losses actually experienced. Moreover, some ISO/RTO loss methodologies continue to embody the pernicious attributes of pancaking. Charges for losses continue to be pancaked despite the fact that some seven years have elapsed since the Commission enunciated its strong preference for eliminating pancaked rates through the formation of ISOs.

7. Transmission losses represent a very substantial cost to Ormet. The transmission loss penalty paid by Ormet to AEP alone is more than 17 MW continuously and has an annual value of approximately $6,000,000 at a power price of $40 per MWH.[4] This value is about 70% to 80% of the annual wires charges that Ormet pays for transmission.

REDUCED LOSSES THROUGH SMD

8. The Commission has correctly focused on two factors that can reduce losses: (a) proper design and operation of a transmission system and (b) locating generation in high-cost load pockets as a substitute for transmission upgrades.

[3] It is especially noteworthy that in New York the cost of congestion exceeds the transmission revenue requirement by 23% and that the dollar amount of losses compares to one third of the transmission revenue requirement. In PJM, line losses represent a 59% surcharge on top of PJM's total transmission revenue requirement.

[4] At its Hannibal, Ohio location, Ormet uses approximately 535 MW of power at a very high annual load factor in producing aluminum (about 4.6 million MWH per year). Ormet now receives network transmission service from American Electric Power ("AEP") through Buckeye Power, Inc., a generation and transmission cooperative, and Ormet acquires its power from third party suppliers in amounts generally exceeding 500 MW. Much of Ormet's power is purchased outside AEP and delivered "into AEP," meaning that losses incurred by Ormet in moving power to AEP across other transmission systems are not explicitly charged to Ormet but are instead reflected implicitly in the price that Ormet pays for power delivered at the border of AEP's system.

However, Ormet is concerned that the SMD NOPR does not go far enough in addressing these issues. First, it is my experience that congestion is increasing and that a substantial proportion of the few upgrades that are being made to the nation's transmission grid is being financed (and often paid for) by newly interconnecting generators and by transmission customers seeking more service – not by RTOs or transmission owners. Even the premium rates of return on transmission being offered under Commission policies have not stimulated substantial new upgrades by many transmission owners. The customer's reward for bearing those upgrade costs under present Commission policies is an entitlement to a credit against transmission charges, a reward that – for the customer - takes the sting out of being forced to provide the upfront capital to finance upgrades. Unfortunately, that credit has been eliminated in the SMD NOPR. Substituted in place of the transmission credit are congestion revenue rights ("CRRs"). It is my understanding, however, that to the extent an upgrade eliminates transmission congestion, the entity that pays for the upgrade receives no payments through CRRs. Worse yet, the CRR mechanism under the SMD NOPR introduces a substantial free-rider effect in that customers that do not pay for upgrades benefit from the reduced congestion when other customers pay for those upgrades.

9. Hence, the Commission has proposed an upgrade policy under which the proponent of transmission upgrades will have little incentive (a) to make most upgrades and (b) when an upgrade is made – to make anything more than the smallest possible upgrade. The entity forced to upgrade transmission will have an incentive to eliminate congestion only for itself and not for others. This is not a desirable public policy in view of the immense economies of scale that continue to be associated with constructing transmission. In other words, one would expect the Commission to be promoting a policy that encourages each upgrade to be maximized so as to minimize congestion (and power costs), to minimize the potential for bottlenecks in the permitting process and to make the best and highest use of lands taken from the public through eminent domain. Instead, the SMD proposal seems likely to encourage piecemeal, sub-optimal upgrades, each

of which is likely to be subjected to its own regulatory delays. The adverse effects of this proposal have been compounded by the financial collapse of the independent power production sector. That collapse has greatly reduced the ability of that sector to build new power plants in load pockets as a substitute for transmission upgrades. Clearly, stronger measures are needed in order to encourage needed upgrades of the nation's transmission grids.

BACKGROUND ON LOSSES

10. A primary source of the inaccuracy and inequity in some ISO/RTO loss charges is that methodologies for loss quantification and allocation are often based on confusion about the nature of losses and resulting fictions that bear little, if any, relationship to the underlying facts or engineering fundamentals. By employing those fictions, however, transmission owners all too often succeed in providing a pretext (a) for collecting payment for losses that vastly exceed the losses actually experienced and (b) for allocating losses to transmission customers in a manner that favors the owner of the transmission system and/or its generating affiliates. In order to clarify the issue and to counter the fictions surrounding losses, I have set forth below a basic primer on how losses should be measured and recovered.

11. There are many reasons for the claimed confusion about losses. One reason is that losses are not linear. That is, losses on a transmission line or transformer vary with the square of the power flowing on that line or transformer. When one doubles the flow on a transmission line, the losses quadruple. In addition, the flow of reactive power (volt amperes reactive or "VARs") causes losses in the same way that the flow of useful or "real" power causes losses. And finally, power on a grid flows by displacement. This means that introducing generation often causes a reduction of flow on lines experiencing high losses and negative incremental losses. Luckily, these concepts are far less complex than they appear and they can be – and are - easily handled by computers. Both overall grid losses and the marginal losses attributable to a change in system conditions can be

calculated with great precision if one knows the levels of load and the sources of generation on a grid.

12. In its Form 715 filings, the Commission already possesses a substantial database of load flow models from which it can ascertain the overall level of load losses prevailing in regional grids and in individual control areas. This database is an extremely valuable tool for anyone interested in determining the capabilities of a regional grid for purposes of interconnecting a new generator or transmitting power across that grid. My firm uses the Form 715 load flow database extensively in our work on behalf of generation developers and transmission customers and owners. To be sure, the Form 715 database does not include many lower voltage sub-transmission lines and transformers that may affect overall system losses, but most of the pertinent bulk power facilities are included. We urge the Commission to employ the capabilities of its Staff and this database as a sanity check on the very high level of losses being sought by some RTOs.

13. Transmission losses reflect the difference between (a) the energy input at the transmission level (excluding the losses occurring in Generator Step Up transformers) and (b) the energy taken out of the transmission system (including deliveries to other transmission systems, to customers served at the transmission and sub-transmission level and to distribution systems). Transmission losses are caused by two kinds of phenomena – losses that occur by current flowing through the system ("load losses') and losses caused by energizing the transmission system ("no load losses"). Load losses account for roughly 94% of the total losses.

14. Load losses are dependent on (a) the resistance of a conductor times (b) the square of the current flowing through a conductor. In general, the total amount of "load losses" is proportional to the average resistance between the points at which energy enters the transmission system and the points at which energy leaves the transmission system for delivery to distribution systems. In the physical world, electrical losses are turned into thermal energy that warms the conductors. Losses

are dependent on line loadings, which are in turn dependent on load conditions and the distribution of energy sources and sinks throughout the transmission system.[5]

15. Losses can be either positive or negative. Two equal and opposite transactions cancel out one another's flows and the associated losses. Depending upon the system configuration and the system's load and generation pattern, each power transaction results in power flows through transmission lines that are higher or lower than those that existed prior to the transaction.

16. Distance traveled by a transaction is often assumed to be a determinant in the associated losses, but that is clearly incorrect in many instances. For example, increasing the output of a generator connected by lightly loaded transmission lines to a load 50 miles away will cause fewer losses than would increasing the output of a generator connected by heavily loaded lines to a load located 20 miles away. That outcome can occur because an increase in current flow affects load losses much more than does an increase in resistance, which tends to be distance-related.

17. Contrary to one popular fiction, losses do not necessarily increase with the number of transactions conducted on a transmission system, with the distance a transaction is deemed to travel or with the number of control area boundaries that are crossed, either directly on a contract path or by loop (parallel) flow. Some elements of that fiction are easily disproved. Assume, for example, that a regional grid has two identical transmission systems (A and B can be adjacent or interconnected by multiple zones between them), each of which has an identical load (100 MW) and equal amounts of generation and each of which experiences 2% losses (2 MW). To start with, assume no transactions are taking place between the two systems and that each system is served solely by its own generation (each system is required to supply 102 MW). Assume further that

[5] Corona losses are associated with ionization of the air around an energized conductor. Corona losses tend to be quite small, are dependent on climatic conditions and tend to be an issue with respect to radio interference. Electrical Transmission and Distribution Reference Book, Central Station Engineers of the Westinghouse Electric Corporation (1964) at 57 *et seq*.

each delivery to load is properly charged with 2% losses. Then, assume transactions commence between System A and System B and that all of the generation connected to System A is sold to serve the loads connected to System B and vice versa. Nothing physical would change in going from the intra-system transactions to the transactions between the systems. But under the loss methodologies used by MISO and previously proposed by Alliance RTO, each of the transactions would be charged more than 4% losses (4+MW), 2% on the originating system plus another 2% on the receiving system plus a percentage of the average losses in other zones in the ISO/RTO (each system is required to supply more than 104 MW). A rough calculation we performed in March of 2002 shows that, if all of the 12 FERC jurisdictional companies initially included in MISO were to pancake losses in accordance with the above example, the MISO companies would over-collect losses by an amount valued at approximately $375 million per year. The value of this over-recovery would increase to the extent that any former Alliance, SPP and TransLink constituent companies have been added to MISO. In other words, the inaccuracies and inequities of employing this fiction are compounded when multiple systems are interconnected.

18. In fact, the overall transmission losses on a network tend to remain remarkably stable no matter where the power source for any given load is located. Intuitively, one can see why that is the case from the simple two-system example with System A and System B just discussed. And this stability of overall losses tends to prevail no matter how many transactions take place on a network, no matter how many control areas are crossed by each transaction, no matter what distance separates the source and the sink for any given transaction and irrespective of how generation is dispatched. To be sure, there can be substantial changes in overall losses, but for any given load level, the loss percentage tends to remain the same over the grid as a whole.

19. When an RTO (or ISO) is formed from multiple systems, the RTO average losses are equal to the weighted average loss rates of each system in the RTO. In other words, if ten systems which each have 2% losses join an RTO, the average RTO

losses will be 2%. This occurs because we add losses to the loss percentage numerator and loads to the denominator of the percentage in roughly equal proportions. Thus, the overall loss percentage remains relatively stable as systems are combined. Pancaking is incorrect because it merely adds losses to the numerator without taking account of additional loads in the denominator. The bottom line is that average losses should not increase for any transaction just because that transaction begins to take place under the auspices of an RTO; yet, that would be the case with some RTO loss methodologies. Also, over the long term, as the RTO takes over regional transmission planning and implements transmission upgrades in order to reduce transmission congestion, the RTO can expect to experience a decrease in average RTO transmission losses.

20. Expanding a system from a single utility (such as each of the single operating companies of the American Electric Power Company -- or "AEP") to a larger control area (such as the AEP control area) does not change the fact that energy tends to flow, by displacement, from each generator to the nearest loads. Similarly, expanding from individual utilities to a regional RTO does not change the fact that energy flows by displacement. Just as percentage losses remain relatively constant when measured over a multi-company control area organized as a holding company, rather than a single system, percentage losses should not increase when measured over an RTO composed of multiple-company control areas. Energy still flows by displacement, and the associated loss percentage should remain relatively stable.

APPROPRIATENESS OF AVERAGE LOSSES RATHER THAN MARGINAL LOSSES

21. Ormet recommends that, at least initially (and hopefully for the long term as well), transmission losses be recovered on an average cost basis with an on-peak and off-peak component. Ormet makes this recommendation for the following reasons:

A. As noted by the Commission, average losses are significantly simpler to apply. As compared to loss recoveries based on average losses, recovering losses on the basis of marginal losses adds a significant layer of complexity especially when integrated with the LMP methodology. This is so much the case that PJM initially dispensed with the use of marginal losses in setting up PJM's approach to LMP. Instead of trying to implement a complex marginal loss methodology, the RTOs should initially keep things simpler in order to get up and running as soon as possible.[6]

B. An average loss methodology provides a measure of price certainty that is not achievable with a marginal loss methodology. Lack of price certainty discourages parties from entering into transactions. For example, under a marginal loss methodology, a customer contemplating a transaction is confronted by the possibility that it may be assigned losses ranging between 0% and 10+%. If the transaction has a small marginal profit of 5%, the potential seller/buyer would hesitate to complete the transaction even if it knew that most transactions would incur marginal losses under 5%. At this stage in the formation of RTOs, price certainty is critical for developing a market.

C. The average loss methodology provides more price transparency. Whereas the burden and magnitude of average losses will be known in advance by customers and transmission providers, the calculation of marginal losses would be unpredictable because the method for determining marginal losses is complex and opaque and can produce volatile results.

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[6] However, in developing the software that will govern the calculation of LMP, provision should be made for later incorporating marginal losses into the LMP methodology.

D. Use of an average loss methodology can easily be adapted to provide an enhanced price signal by simply determining on-peak and off-peak average losses. Further price signals can be given by implementing seasonal on-peak and off-peak average loss factors (summer, winter, monthly, etc.).

22. Consistent with the above recommendation, recovering the cost of transmission losses based on predetermined fixed percentages would simplify the loss recovery process, provide price certainty and price transparency and yet still send price signals adequate to promote the economically efficient usage of the transmission system (by using seasonal on-peak and off-peak loss factors). With average losses, allowing transmission customers to pay their assigned losses either in cash or in kind would be preferable and would not be more complicated than the process currently in use.

PANCAKING OF LOSSES NEEDS TO BE ELIMINATED

23. One of the biggest operational contributors to the undue inflation of transmission losses is the pancaking of losses. Although the elimination of pancaked losses may be implicit in the SMD NOPR, Ormet recommends that the Commission should make that elimination explicit and clarify that pancaking of losses will no longer be permitted.

24. Despite the Commission's all-out effort to eliminate pancaked rates, pancaked losses have continued to survive. Pancaked transmission losses were an integral part of the now-abandoned Alliance RTO and were implemented in the MISO on an interim basis. Not only does Ormet recommend that no pancaked losses be allowed within RTOs, Ormet also recommends that no pancaked losses should be implemented over multiple RTOs.

25. The simple physical fact of energy displacement seems to have been overlooked in those instances in which this Commission has allowed losses to be pancaked on

the apparent, but mistaken theory that increasing the size of a transmission system will increase loss percentages associated with individual transactions.

26. AEP provides a dramatic example of the substantial discrepancies between pancaked and non-pancaked losses. A November 1993 tabulation of transmission losses for AEP operating companies showed that losses within individual operating companies varied from 1.52% to 3.89% on transmission facilities operating at voltages from 138 kV through 765 kV (a weighted average of 2.65%) and from 0.57% to 3.26% on transmission facilities operating at voltages from 23 kV through 88 kV (a weighted average of 1.18%). At that time, AEP's overall weighted average loss was 3.6% for all transmission voltages (23 kV to 765 kV).

	Transmission Losses	
	138 kV to 765 kV	23-kV to 88 kV
APCO	2.86%	1.33%
CSP	1.52%	0.79%
I&M	3.89%	1.16%
KPCO	1.52%	1.32%
KgPC		3.26%
OPCO	2.49%	1.33%
WPCO		0.57%
Total	2.65%	1.18%

If AEP did impose pancaked loss charges across its operating companies, a transaction passing through three companies (I&M, Ohio Power and Appalachian) would be charged losses of 9.24% (if only the losses above 138 kV were included), much higher than the 2.65% average loss factor for all voltages at 138 kV and above. Although AEP does not pancake losses in transactions involving multiple operating companies, it supported the continued pancaking of losses whenever it considered participation in an RTO, both in the case of the Midwest ISO and in the case of the Alliance RTO. The inconsistency of this approach is readily apparent in situations in which a holding company acquires a neighboring system and eliminates the pancaking.

LOSS METHODOLOGIES OF EXISTING RTOS

27. The following table summarizes some of the significant loss attributes of various operating ISOs, RTOs and proposed RTOs. Note that ISO New England, PJM ISO and ERCOT ISO recover non-pancaked average transmission losses ranging from 1.13% to 2.5%, quite consistent with my earlier example of a 2% average transmission loss for an RTO composed of 10 systems, each of which experiences average losses of 2%. Note also that the GAPP/Pancaked Plus loss methodologies result in collection of losses ranging from 3.43% to 8.74%.

Summary of Selected Current Loss Methodologies as of February 2002

Entity	Loss Methodology	Trans. Losses for multiple zone transactions			Comments
		Avg.	High	Low	
NYISO	B-Matrix (incremental)	Unk	Unk	Unk	Used with Locational Based Marginal Pricing (LBMP). Losses settled financially. Calculated hourly.
California ISO	Scaled Marginal Loss Rates	1.26%	17.4%	-7.24%	For 2/27/02 Calculated hourly.
ISO – New England	Non-Pancaked Average Losses	2.47%	3.9%	1.13%	In, Out and Thru Transactions Calculated hourly for within transactions and settled financially.
PJM	Non-Pancaked Average Losses	2.75%	3.00%	2.50%	Currently fixed. Appear to be moving toward Average + LMP (marginal losses).
ERCOT	Non-Pancaked Average Losses	1.88%	2.41%	1.64%	Calculated Hourly.
Midwest ISO[7] (Northern)	GAPP/Pancaked Plus	6.95%	8.74%	4.75%	For use during the transition period (settlement). Calculated twice a year.
Midwest ISO[7] (Southern)	GAPP/Pancaked Plus	4.65%	5.02%	3.68%	For use during the transition period (settlement). Calculated twice a year.
Alliance RTO	GAPP/Pancaked Plus	6.43%	8.59%	3.43%	Proposed by ARTO. Not approved by FERC.

28. The B-Matrix loss methodology calculates incremental losses associated with a transaction by modeling an increment of generation at each node along with an increment of load in the zone. The resulting loss factor is applied to the incremental transaction. Transactions are layered in order to derive loss factors for

[7] Based upon MISO filing in Docket No. ER02-438-000 (Revised Transmission Loss Factors). The Northern Group is composed of Northern States Power Companies (NSP), American Transmission Company (ATC), Alliant Energy Operating Company – West (ALTW), Minnesota Power Company (MP), Otter Tail Power Company (OTP) and Montana-Dakota Utilities Company (WAUE). The Southern group is composed of Cinergy Services, Inc. (CIN), Indianapolis Power & Light Company (IPL), LG&E Operating Companies (LGEE) and Southern Indiana Gas & Electric Company (SIGE).

each transaction. The Scaled Marginal Loss Rates methodology is similar in that it calculates losses at each generating unit and scheduling point by injecting energy at each generating unit bus or scheduling point to serve an increment of demand distributed proportionally throughout the region (ISO control area). These losses are then scaled down by the ratio of expected total losses to total power flow model losses in order to avoid over-collection of losses. This methodology gives locational siting signals for generation siting.

29. The Non-Pancaked Average Losses methodology is essentially the regional average or zonal average approach to losses (or some combination of the two) described earlier that Ormet recommends the Commission advocate as part of the Standard Market Design. In an actual LMP methodology, losses are calculated on a marginal basis.

30. The GAPP[8]/Pancaked Plus loss methodology is a zonal average approach where transactions contained within a single zone (source and sink within the same transmission owner's system) are charged that zone's average loss rate. However, other transactions are charged the zonal average loss rates of the sink zone and source zone plus a percentage of the average losses in other zones based on the Transmission Participation Factor (TPF) matrix, which purports to calculate the percentage of each transaction flowing through each of these other zones. For example, a transaction between zone A (3% average loss) that is directly connected to zone B (3% average loss) in an RTO with multiple zones will be charged for zone A losses (3%) plus zone B losses (3%) plus a portion of each of the other zone losses in the RTO. Under straight pancaked rates, losses would be 6%. However, under the GAPP/Pancaked Plus methodology, losses on average will be higher than 6%. If all the RTO zones experience 3% average losses, the RTO actual average losses on all transactions would also be 3%. However, all transactions over multiple zones under this method will be charged more than 6%

[8] GAPP is the General Agreement on Parallel Paths Experiment Methodology.

for losses, even if some transactions actually reduce RTO average losses. The GAPP/Pancaked Plus as used by MISO and as previously proposed by the Alliance RTO collects far more losses than are actually experienced and places all suppliers that do not own transmission at an economic disadvantage.

31. The GAPP method used by MISO ignores the fact that a transaction may reduce losses as a result of reducing line loadings. That is, two equal and opposite transactions actually cancel out one another's flows and the associated losses. It is clear that the GAPP methodology fails to reflect this fact because the transmission participation factors are positive and equal in each direction. None are negative. Accordingly, a generator inside a load pocket serving a load outside the load pocket (a case in which the transaction reduces losses on lines that are congested) would be charged the same loss rate as would a generator located outside the load pocket scheduled to serve load inside the load pocket (a case in which the transaction increases losses). But it is incorrect to assume that each zonal transmission system that participates in a transaction contributes to the generation of losses. It is particularly incorrect to assume that both the source and the sink zones are affected with 100% of their loss factor, as the MISO method does. The new transaction can either increase or decrease loadings on the lines in both the source system and the sink system and may cause much lower losses to be experienced within the sink. For these reasons, the GAPP methodology and the manner that in which the methodology utilizes TPFs are grossly flawed. This methodology will systematically overcharge for losses and will not encourage the efficient siting of generation.

32. Ormet is located on the AEP transmission system. Because AEP joined PJM and will presumably adopt the PJM loss methodology, Ormet has fewer concerns than it would have had if AEP had joined the MISO and adopted either the MISO loss methodology or the methodology previously proposed by the now-defunct Alliance RTO. Both the MISO methodology and the methodology proposed by the Alliance RTO are GAPP/Pancaked Plus methods that systematically

overcharge for losses. Ormet remains concerned that AEP may press for adoption of the GAPP/Pancaked Plus methodology within its own subsection of PJM.

PAYMENT IN-KIND SHOULD BE ALLOWED

33. The cost of transmission losses occurring within an RTO can be settled in one of two ways: either through an in-kind payment of additional MWh to cover those losses, or through a cash payment to the entity that provides those losses. Ormet recommends that transmission customers be given the option of repaying losses in kind. The reason is quite straightforward: Ormet prefers the certainty that comes from supplying transmission losses at known costs from its own resources in lieu of being subjected to the risks of the market. The volatility and unpredictability of marginal losses would add to these risks to the extent the Commission requires use of marginal losses. The need to preserve the option of providing losses in kind provides further support for use of predetermined, fixed percentage losses as opposed to marginal losses. It would be difficult for Ormet to control the amount and cost of transmission losses if it relied on the energy spot market to serve an unpredictable amount of marginal losses.

THE SEVEN-FACTOR TEST

34. The SMD NOPR addresses the Seven Factor test beginning at paragraph 367:

> c. Test for Transmission Facilities
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> 367. Order No. 888's seven factor test was designed to determine the local distribution component of an unbundled retail sale. The test did not exist prior to Order No. 888 and in fact was created to do something the Commission had never done before – identify local (retail) distribution facilities. Thus, the test identifies all facilities that are not local distribution facilities. We propose that this is the appropriate starting point for determining which facilities belong under the control of an Independent Transmission Provider. To the extent that a transmission owner or Independent Transmission Provider believes that certain facilities should not be under the Independent Transmission Provider's

control, the Independent Transmission Provider may request an exception to this presumptive determination.

368. This proposed test focuses on the presumption that, if a facility is transmission, it belongs under the control of the Independent Transmission Provider. Thus, once a determination is made with the seven factor test, there would be no need for an additional review under the Commission's previous integrated facilities test. In MidAmerican Energy Company, the Commission explained that the Commission's determination of which facilities are transmission is fluid and dependent on actual the [sic] use of the facilities:

> Although we are accepting the state commissions' classification, we reiterate our finding in Order No. 888 that to the extent that any facilities, regardless of their original nominal classification, in fact, prove to be used by public utilities to provide transmission service in interstate commerce in order to deliver power and energy to wholesale purchasers, such facilities become subject to this Commission's jurisdiction and review. In addition, the rates, terms and conditions of all wholesale and unbundled retail transmission service provided by public utilities in interstate commerce are subject to this Commission's jurisdiction and review.
>
> Further, our deference in this proceeding does not affect the Commission's separate determination of what facilities must be under the operational control of RTOs, including ISOs and Transcos. The Commission will make this latter determination, taking into account the seven factors formulated for purposes of determining jurisdiction as set forth in Order No. 888, the ISO principles set forth in Order No. 888, and the principles set forth in the RTO Final Rule.
>
> We note that the determination of which facilities are under the operational control of the Independent Transmission Provider does not dictate transmission pricing.

369. We request comment whether, either in addition to or in lieu of the seven factor test, the Commission should use a bright line voltage test (e.g., 69 kV) to determine which facilities are placed under the control of the Independent Transmission Provider. If so, we seek comment on the bright line, whether we should allow regional variation, and how transmission facilities that are not placed under the control of the Independent Transmission Provider's tariff are treated with respect to open access and rates. [footnotes omitted]

35. Ormet fully supports the comprehensive application of the Seven Factor test on a consistent basis. Basically, the Commission's Seven Factor test allows transmission owners to re-label lower-voltage transmission facilities as distribution facilities, changing their function ("refunctionalization"). Refunctionalization is the process by which the Commission seeks to identify the delivery facilities that are used to move bulk power over the nation's electric grids and to minimize the amount of facilities that are deemed to serve the transmission function by transferring non-grid facilities to the distribution function. Refunctionalization also eliminates most radial transmission facilities from the transmission function, both those radial facilities serving loads and those connecting generators to the grid. Refunctionalization has been carried out by State regulatory bodies in accordance with the Seven Factors set forth in Order No. 888, but not all transmission owners have gone through that process. Moreover, even some of those transmission owners who have gone through the process may need to undergo a periodic reassessment under the Seven Factor test, particularly in areas in which significant new generation is being interconnected.

36. The Seven Factors test was created by FERC in order to distinguish transmission facilities from distribution facilities properly. The objective was to foster efficiency and competition by recovering only transmission costs through transmission rates. However, the application of the Seven Factors by some utilities has had anticompetitive consequences and, in particular, has targeted (a) industrial customers that would qualify as transmission-only customers absent the refunctionalization as well as (b) inside-the-fence generation. Refunctionalization has also limited the facilities that a transmission owner must transfer to the operational control of an RTO in the past, and the facilities that a transmission owner might be required to transfer to the Independent Transmission Provider in the future.

37. Refunctionalization has had a beneficial effect on transmission rates in that, after the process has been completed, transmission customers are no longer required to bear the costs of - and transmission losses on - many facilities that do not have as

their primary function moving bulk power across a grid or network. Only those customers who use lower voltage sub-transmission facilities - and the radial facilities connected to loads and generators - pay for those facilities, usually in accordance with the Commission's preference for directly assigning costs of the facilities excluded from the transmission rate base. Properly applied, the Commission's direct assignment policies prevent rolling the costs of all distribution facilities into a single distribution rate in ways that are unduly discriminatory. Under a properly determined direct assignment, transmission customers using only high-voltage "distribution" facilities do not pay for low-voltage "distribution" facilities.

38. Ormet believes it is unnecessary to establish a "bright line" voltage such as 69 kV as the dividing line between transmission facilities and distribution facilities. Ormet's position is based on the beneficial effects of the Seven Factors test, the great variation in backbone voltages from region to region (what is legitimately considered "distribution" on the AEP System might legitimately be considered backbone "transmission" on Bangor Hydro or Black Hills Power & Light), the large investment already made by the Commission and State commissions in implementing the Seven Factors test and the numerous safeguards against abuse that have been engrafted onto the Seven Factors test since it was first proposed.

39. In the past, there were some notorious cases in which utilities were allowed to recover the costs of 23 kV facilities and other low-voltage facilities in their transmission rates, needlessly driving up transmission costs and rates and impeding the development of bulk power markets.[9] This type of abuse should be mitigated by the correct application of the Seven Factor test. Many transmission owners have yet to go through the refunctionalization process, with the result that their rates are far higher than their rates would be after refunctionalization and

[9] See, for example, Public Service Company of New Hampshire, ER89-207-000/001/003/004, Order Accepting Rate Schedules 46 FERC ¶61,419 (March 31, 1989), Order Denying Rehearing 49 FERC ¶61,030 (October 6, 1989), Order Denying Reconsideration … 50 FERC ¶61,107 (February 1, 1990), Order on Remand … 50 FERC ¶61,244 (August 7, 1991), and Letter Order 58 FERC ¶61,264 (March 2, 1992).

higher than the rates of those transmission owners that have gone through the process.

INTER-RELATIONSHIP OF SEVEN FACTOR TEST AND VOLTAGE DISCOUNTS

40. Development of a proper policy on transmission losses is related to the Seven Factor test. Ormet recommends that the Commission make its first order of business to require all RTO members to refunctionalize their transmission systems in a uniform manner by dropping out lower voltage sub-transmission facilities from the coverage of transmission rates and transmission losses. As its second order of business, the Commission should require all RTOs and their member transmission systems to adjust transmission losses downward to reflect the fact that losses will be experienced only on those facilities that remain a part of the RTO's transmission system after application of the Seven Factor test.

41. I also recommend implementation of a voltage discount for transmission losses and for access charges as well. I recognize, however, that applying the Seven Factor test would eliminate charges and losses for lower voltage facilities and thereby help alleviate the discrimination that arises from the lack of a voltage discount.

VOLTAGE DISCOUNT FOR TRANSMISSION LOSSES

42. To the extent that a comprehensive application of the Seven Factor test to the AEP System does not result in elimination of most facilities operating below 138 kV from the transmission function, Ormet recommends that losses (and access charges) be voltage differentiated. This should be done in order to reflect the lower amount of costs and losses typically experienced on high-voltage facilities. Voltage differentiation is done routinely in retail tariffs for bundled industrial customers taking service at transmission voltages. Quite apart from the situation on the AEP System, it would be desirable for each load serving entity to calculate losses (and access charges) that are similarly differentiated by voltage (for

unbundled customers as well as for bundled customers) to the extent that application of the Seven Factor test leaves many low-voltage facilities in the transmission function. This will become important in the future when – as expected - RTOs are expected to transition away from zonal transmission rates to a single RTO-wide average transmission rate that would apply across all zones.

43. Voltage-differentiated losses (and access charges) may be needed by unbundled transmission customers in order to eliminate undue discrimination that they would otherwise be subjected to. Voltage differentiation takes on more importance now that the Commission seeks to require load serving entities to take transmission service for their bundled native load customers through the RTO tariff.

44. Voltage-differentiation is a commonplace feature of retail tariffs and needs to be replicated in the tariffs of RTOs in order to minimize the opportunities for undue discrimination. As an example, I urge the Commission to consider the retail rate schedules of a large Midwest IOU that were issued and became effective on January 1, 2001. The nominal voltage levels for this IOU are defined:

> Primary Distribution System is defined as "Alternating current, 60 cycles at nominal voltages of 12,740 and 34,500 volts, 3 phase."
>
> Subtransmission is defined as "Alternating current, 60 cycles, 3 phase at nominal, unregulated voltage of 23,000, 34,500 and 69,000 volts."
>
> Transmission is defined as "Alternating current, 60 cycles, 3 phase at nominal unregulated voltage of 138,000 volts."

Wholesale customers are served at voltages equivalent to Primary, Sub-transmission and Transmission voltages.

45. This Midwest IOU's Schedule GS-4 (General Service – Large) covers service in amounts greater than 8,000 KW and reflects the following rates and charges:

GS-4 Voltage Level	Generation Demand $/kw-month	Transmission Demand $/kw-month	Distribution Demand $/kw-month	Energy Charge $/MWH
Primary	$ 7.14	$ 1.68	$ 2.65	$ 15.70
Subtransmission	$ 6.95	$ 1.63	$ 0.95	$ 15.64
Transmission	$ 6.83	$ 1.61	$ 0.21	$ 15.61
Discount From Primary Voltage Level				
Subtransmission	2.66%	2.98%	64.15%	0.38%
Transmission	4.34%	4.17%	92.08%	0.57%

46. This Midwest IOU's Schedule GS-3 (General Service – Medium/High Load Factor) also reflects the following rates and charges:

GS-3 Voltage Level	Generation Demand $/kw-month	Transmission Demand $/kw-month	Distribution Demand $/kw-month	Energy Charge $/MWH
Primary	$ 6.53	$ 1.56	$ 3.25	$ 17.16
Subtransmission	$ 6.34	$ 1.52	$ 2.85	$ 17.04
Transmission	$ 6.24	$ 1.51	$ 2.29	$ 16.98
Discount From Primary Voltage Level				
Subtransmission	2.91%	2.56%	12.31%	0.69%
Transmission	4.44%	3.21%	29.54%	1.05%

47. The above data indicate that this IOU offers a voltage discount on the demand and energy rates applicable to large retail customers that this IOU does not offer to wholesale transmission customers. The differentials in transmission demand charges reflect differences in transmission costs by voltage level, and the differentials in generation demand and energy costs reflect differentials in losses by voltage level. The voltage discount applicable to retail charges indicates that customers taking service at 138 kV are charged losses that are lower than those applicable to equivalent customers served at sub-transmission voltages and those applicable to equivalent customers served at primary voltages. No similar discounts are offered by this particular IOU to wholesale transmission customers taking transmission services at 138 kV for the basic access charge for transmission services or for transmission losses.

48. Under the Commission's comparability principle, a vertically integrated utility is obligated to allow wholesale customers to make use of its transmission system on the same bases on which the utility itself makes use of its transmission system in serving its own loads. FERC Statutes and Regulations ¶31,035 at p. 31,647, citing a decision on AEP's original open access tariff. *American Electric Power Service Corporation*, 67 FERC ¶61,168 at 61,490 (1994). The Commission clearly focused on the transmission service that a utility renders to itself at retail when devising its comparability test.

49. The previous table at paragraph 26, which describes AEP's losses as of November 1993, shows the importance of differentiating loss charges by voltage. Note that including 1.18% for losses associated with facilities operating below 138 kV drives the weighted average loss from 2.65% to 3.6% in that time period. Including losses on low voltage facilities, as AEP and most other utilities tend to do, is unreasonably burdensome on an entity such as Ormet that takes service at 138 kV and that makes negligible, if any, use of facilities operating at lower voltages.

50. This concludes my affidavit.